California Environmental Protection Agency

Air Resources Board

Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California

Stationary Source Division

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The Staff of the Air Resources Board developed this preliminary draft version as part of the Low Carbon Fuel Standard Regulatory Process

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These comments will be compiled, reviewed, and posted to the LCFS website in a timely manner.

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SUMMARY

CA-GREET Model Pathway for ULSD from Average Crude Refined In California

A Well-To-Tank (WTT) Life Cycle Analysis of a petroleum based fuel pathway includes all steps from crude recovery to final finished fuel. Tank-To-Wheel (TTW) analysis includes actual combustion of fuel in a motor vehicle for motive power. Together, WTT and TTW analysis are combined to provide a total Well-To-Wheel (WTW) analysis.

A Life Cycle Analysis Model called the **G**reenhouse gases, **R**egulated **E**missions, and **E**nergy use in **T**ransportation (GREET)[1] developed by Argonne National Laboratory has been used to calculate the energy use and greenhouse gas (GHG) emissions generated during the process of transforming crude to produce Ultra Low Sulfur Diesel (ULSD). The model however, was modified by TIAX under contract to the California Energy Commission during the AB 1007 process[2]. Changes were restricted to mostly input factors (electricity generation factors, crude transportation distances, etc.) with no changes in methodology inherent in the original GREET model. This California-modified GREET model, herein referred to as "GREET", forms the basis of this document. The pathway described in this document is for average crude (both in-state production and overseas crude transported to CA) that is refined in CA. The values, assumptions, and equations used in this document are from the CA-modified GREET model (greet1.7ca_v98.xls). This model is available for download from the Low Carbon Fuel Standard website at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. The values shown in this document are preliminary draft values and staff is in the process of evaluating them. The areas that staff may revise include emission factors, energy intensity factors, % fuel shares, transport modes and their shares, agricultural chemical use factors, co-product credit methodologies, etc.

The pathway described in this document accounts for crude recovery, transport, refining of crude in a typical California refinery, transport of finished fuel and use of this fuel in a passenger vehicle. Figure 1 details the discrete components that form the ULSD pathway, from crude recovery through final finished fuel and use in a transportation vehicle. Utilizing the energy and GHG emissions from each component, a total for the entire ULSD pathway is then calculated.

Several general descriptions and clarification of terminology used throughout this document are:

- GREET employs a recursive methodology to calculate energy consumption and emissions. To calculate WTT energy and emissions, the values being calculated are often utilized in the calculation. For example, crude oil is used as a process fuel to recover crude oil. The total crude oil recovery energy consumption includes the

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1 http://www.transportation.anl.gov/software/GREET/
2 http://www.energy.ca.gov/ab1007/

direct crude oil consumption AND the energy associated with crude recovery (which is the value being calculated).

- Btu/mmBtu is the energy input necessary in Btu to produce or transport one million Btu of a finished (or intermediate) product. This description is used consistently in GREET for all energy calculations. There are 1055 million Btu in one MJ of energy, so in order to convert one million Btu into MJ, multiply the million Btu by 1055.

- gCO_2e/MJ provides the total greenhouse gas emissions on a CO_2 equivalent basis per unit of energy (MJ) for a given fuel. Methane (CH_4) and nitrous oxide (N_2O) are converted to a CO_2 equivalent basis using IPCC global warming potential values and included in the total.

- GREET assumes that VOC and CO are converted to CO_2 in the atmosphere and includes these pollutants in the total CO_2 value using ratios of the appropriate molecular weights.

- Process Efficiency for any step in GREET is defined as:

  Efficiency = energy output / (energy output + energy consumed)

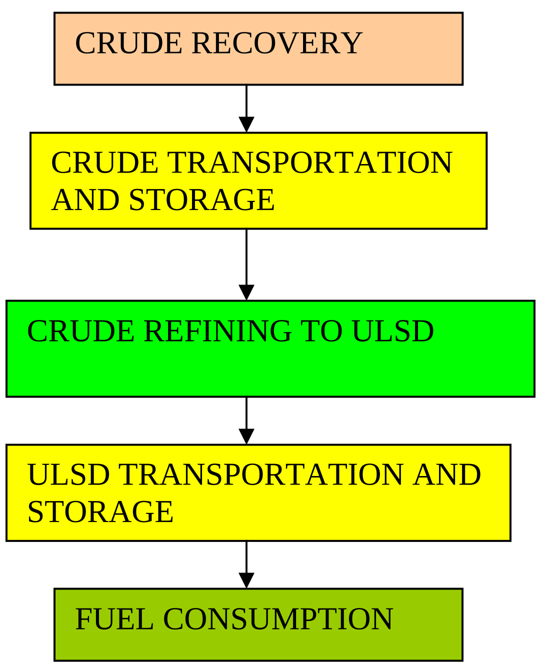

Figure 1. Discrete Components of Crude to ULSD Pathway

Table A provides a summary of the Well-To-Tank (WTT) and Tank-To-Wheel (TTW) energy use and GHG emissions for this pathway. Energy use is presented as Btu/mmBtu and GHG emissions are reported as gCO_2e/MJ.

Table A. Energy Use and GHG Emissions for the ULSD Pathway

	Energy Required (Btu/mmBtu)	**% Energy Contribution**	**Emissions (gCO_2e/MJ)**	**% Emissions Contribution**
Well to Tank				
Crude Recovery	86,477	6.8%	6.6	6.6%
Crude Transport and Storage	10,076	0.8%	2.2	2.3%
Crude Refining (CA)	175,173	13.7%	11	11.1%
ULSD Transport and Storage	4,214	0.3%	0.3	0.3%
Total (Well To Tank)	**275,940**	**21.6%**	**20.1**	**20.3%**
Tank to Wheel				
Carbon in Fuel	1,000,000	78.4%	74.1	74.5%
Vehicle CH_4 and N_2O			5.2	5.1%
Total (Tank To Wheel)	**1,000,000**	**78.4%**	**79.3**	**79.6%**
Total (Well To Wheel)	**1,275,940**	**100%**	**99.4**	**100%**

Note: percentages may not add to 100 due to rounding

From Table A above, the WTW analysis of ULSD indicates that 1,275,940 Btu of energy is required to produce 1 (one) mmBtu of available fuel energy. From a GHG perspective, 99.4 gCO_2e/MJ of greenhouse gas emissions are generated during the production and use of ULSD in a passenger vehicle. Please note that the GHG emissions are not adjusted for vehicle efficiency. The value reported within this document varies from previously reported values of ~91 for several reasons: The current value includes both N_2O and CH_4 emissions and the crude recovery efficiency is 93.9%, which has been modified from 98.0%. For a more detailed explanation of the difference in crude recovery efficiency, see Section 1.1. Note that rounding of values has not been performed in several tables in this document. This is to allow stakeholders executing runs with the GREET model to compare actual output values from the CA-modified model with values in this document.

Figure 2 shows the percentage of specific contributions of each of the discrete components of the WTW fuel pathway presented in Table A. The charts are shown separately for energy use and GHG emissions. From an energy use viewpoint, energy in fuel (78.4%), crude refining (13.7%), and crude recovery (6.8%) dominate the WTW energy use. From a GHG perspective, combustion of fuel (79.6%), crude refining (11.1%), and crude recovery (6.6%) dominate the GHG emissions for this pathway.

The section below provides an expanded view of the summary results presented here. Appendix A provides detailed description of the assumptions, input values and equations used in the model. Appendix B provides a table of input values used in the calculations in this document.

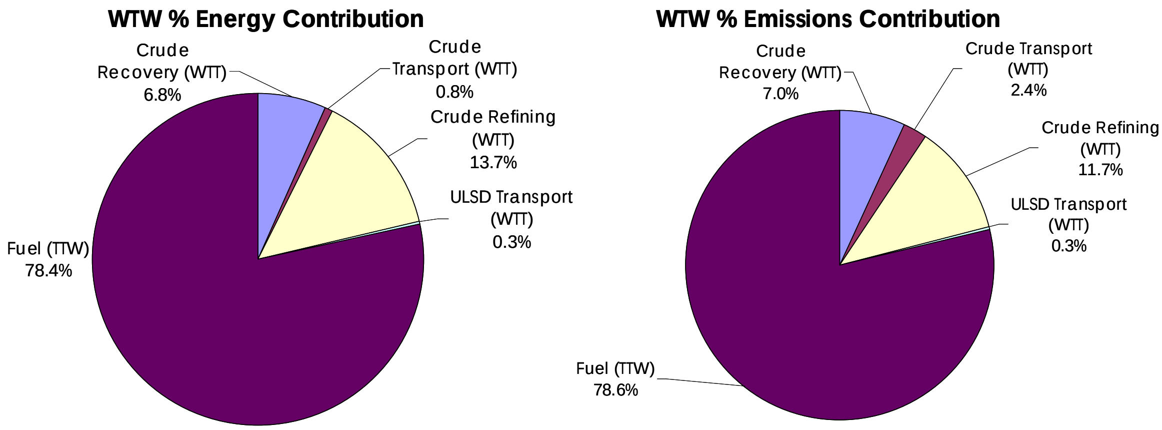

Figure 2. Energy and GHG Contributions of ULSD

WTT Details-Crude Recovery

Table B provides a breakdown of energy use for crude recovery. Crude recovery utilizes process energy which GREET depicts as being derived from a combination of several fuel types to include crude itself, residual oil, diesel, gasoline, natural gas and electricity. As an example, natural gas is combusted in a boiler to generate heat which then runs a turbine to generate electricity. This feature is captured in the electricity fuel share part of the energy mix. The table indicates that 86,477 Btu of energy is required to recover crude containing 1 mmBtu of energy. Detailed calculations are provided in Appendix A.

Table B. Total Energy Use for Crude Recovery

Fuel Type	**Btu/mmBtu**
Crude oil	704
Residual oil	758
Diesel	12,074
Gasoline	1,664
Natural gas	43,165
Electricity	28,083
Feed Loss	28
Total energy for crude recovery	**86,477**

The GHG emissions associated with the transformation of fuel sources to useful process energy for crude recovery is shown in Table C below. 6.60 grams of CO_2 e GHG emissions are generated during the crude recovery step of this pathway. Additional details are provided in Appendix A.

Table C. Total GHG Emissions from Crude Recovery

GHG Emissions	**gCO_2e/MJ**
CO_2	6.08
CH_4 (combustion)	0.39
CH_4 (non-combustion)	0.05
N_2O	0.03
CO	0.04
VOC	0.01
Total GHG emissions	**6.60**

Note: Non-combustion methane leaks during recovery operations

WTT Detail - Crude Transportation and Storage

Table D shows the energy necessary for transporting crude via ocean tanker and pipeline to California refineries. The proportional split between these two modes of transport are calculated from the average crude mix arriving in California, both from within the state as well as from overseas. Detailed breakdown of proportions utilized in the calculations are provided in Appendix A. A small energy loss attributable to feed losses is also captured in this analysis. As shown in Table D, crude transport utilizes 10,076 Btu of energy for every mmBtu of crude transported.

Table D. Energy Consumed for Crude Transport

	Btu/mmBtu
Feed Loss	62
Ocean Tanker	5,845
Pipeline	4,169
Total	**10,076**

Table E captures GHG emissions from crude transport in ocean tankers and pipelines. The fuel consumption and other specifics necessary for this calculation are detailed in Appendix A. Crude transport by the two types of transport weighted proportionally generates 2.24 gCO_2e GHG emissions for every MJ of crude transported.

Table E. Total GHG Emissions Crude Transport and Distribution

GHG	**gCO_2e/MJ**
CO_2	0.71
CH_4	1.53
N_2O	0.00
CO	0.00
VOC	0.00
Total GHG emissions	**2.24**

WTT Detail - Crude Refining

Table F below shows that 175,173 Btu of energy is required to produce 1 mmBtu of finished fuel. Again, each source of fuel has associated GHG emissions in its transformation into useful energy and these are shown in Table G below. The refining process generates 9.94 gCO_2e GHG emissions per MJ of finished fuel. This is combined with non-combustion methane from venting of associated gas which adds an additional 1.06 gCO_2e providing for a total of 11.0 gCO_2e per MJ of fuel. Details of all the calculations are presented in Appendix A.

Table F. Energy Required for Crude Refining to ULSD

Fuel Type	**Btu/mmBtu**
Residual Oil	10,805
Natural Gas	66,152
Electricity	14,044
Refinery still gas	84,172
Total energy for refining	**175,173**

Table G. GHG Emissions from Crude Refining to ULSD

GHG	**gCO_2e/MJ**
CO_2	9.66
CH_4 (combustion)	0.24
N_2O	0.03
CO	0.01
VOC	0.002
Total (without CH_4 non-combustion)	9.94
CH_4 (non-combustion)	1.06
Total	**11.0**

WTT Detail – ULSD Transport and Storage

Table H provides a summary of the energy expended to transport finished ULSD via pipeline and Heavy Duty Diesel (HDD) truck from refineries to a blending station. From Table H, this component of the pathway utilizes 4,214 Btu of energy for every 1 mmBtu of ULSD transported. The transportation through pipeline and HDD truck generates GHG emissions which are shown in Table I below. A total of 0.3 gCO_2e GHG emissions are generated for every 1 MJ of ULSD transported.

Table H. Energy Use for ULSD Transportation and Distribution

Transport mode	**Btu/mmBtu**
Feed Loss	145
ULSD transported by pipeline	625
ULSD Distribution by HHD truck	3,444
Total	**4,214**

Table I. GHG Emissions from Transporting and Distributing ULSD

	GHG (gCO_2e/MJ)
Pipeline	0.04
HHD Truck	0.25
Total	**0.3**

TTW - Tank to Wheel Energy and GHG Emissions Summary

Table J below provides a summary of the carbon in fuel calculations, details which are provided in Appendix A. It also includes a summary of CH_4 and N_2O emissions generated during combustion in a passenger vehicle. These emissions were not included in the previous tank to wheel analysis. A total of 79.3 gCO_2e GHG emissions are generated from the TTW portion of the ULSD pathway. Vehicle efficiency is not included in the GREET analysis.

Table J. Tank To Wheel Summary for ULSD

Parameter	**GHG (gCO_2e/MJ)**
CO_2 (carbon in fuel)	74.1
N_2O	4.8
CH_4	0.4
Total	**79.3**

APPENDIX A

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SECTION 1. CRUDE RECOVERY

1.1 Energy Use for Crude Recovery

Energy requirements in GREET for this component utilizes a crude recovery efficiency which is used to calculate energy needs for this process. The crude recovery efficiency used here is a weighted average and takes into consideration crude extracted in California as well as crude recovered overseas. The default value in GREET is 98% which reflects an average crude processed in the United States. The 93.9% value represents an estimate of a mix of conventional oil recovery and Thermally Enhanced Oil Recovery (TEOR) as detailed in the AB1007 analysis. TEOR requires steam to be injected into the reserves and therefore uses more energy than conventional oil reserves. Natural gas is most commonly the fuel used to generate steam. Table 1.01 provides details on how this efficiency is used to calculate energy requirements for this part of the pathway. Here, fuel shares describe a breakdown of how different fuels are used as an energy source for various operations used in crude recovery (e.g. natural gas share of energy input is 62%). The fuel shares are default GREET values. Note that the inverse of efficiency is multiplied by 10^6 since we calculate Btu per million Btu of fuel. For flared natural gas, the GREET default value is 16,800 Btu/mmBtu.

Table 1.01 Details on How Efficiency is Used to Calculate Energy Consumption for Crude Recovery

Fuel Type	**Fuel Shares**	**Relationship of Recovery Efficiency (0.939) and Fuel Shares**	**Btu/mmBtu**
Crude oil	1%	$(10^6)(1/0.939 – 1)(0.01) = 648$	648
Residual oil	1%	$(10^6)(1/0.939 – 1) (0.01) = 648$	648
Diesel fuel	15%	$(10^6)(1/0.939 – 1) (0.15) = 9,726$	9,726
Gasoline	2%	$(10^6)(1/0.939 – 1)(0.02) = 1,297$	1,297
Natural gas	62%	$(10^6)(1/0.939 – 1)(0.62) = 40,201$	40,201
Electricity	19%	$(10^6)(1/0.939 – 1)(0.19) = 12,320$	12,320
Feed Loss	0.043%	$(10^6)(1/0.939 – 1)(0.00043) = 28$	28
Natural Gas Flared		GREET Default Value	16,800

Note: Crude Recovery Efficiency in GREET is defined as energy in crude recovered / (energy in crude recovered + energy consumed to recover crude)

The values in Table 1.01 are then adjusted to account for upstream losses from various processes during crude recovery. Table 1.02 depicts the adjustments to the values from Table 1.01 for each fuel type, accounting for loss factors associated with the WTT energy for each fuel used during crude recovery operations. Table 1.03 provides values and descriptions for the equations used in Table 1.02.

Table 1.02 Adjustment to Values in Table 1.01 to Account for Upstream Losses

Fuel Type	Formula	Btu/mmBtu
Crude oil	$648 (1 + A/10^6)$	704
Residual oil	$648 (1 + (B*D+ C)/ 10^6)$	758
Diesel fuel	$9,726 (1 + (B*F + E)/ 10^6)$	12,074
Gasoline	$1,297 (1 + (B*H + G)/ 10^6)$	1,664
Natural gas	$40,201 (1 + I/10^6)$	43,165
Electricity	$12,320 (K+ J)/ 10^6$	28,083
Feed Loss	28	28
Total WTT energy for crude recovery		**86,477**

Note: Values like 648, 9726 etc. above are from Table 1.01 in this document.

Table 1.03 Details for Formulas in Table 1.02

Quantity	Description
A = 86,477	WTT energy in Btu for crude recovery at the oil field. This value calculated as the total WTT energy for crude recovery in Table 1.02 above. It is also an input the total WTT energy calculation This is one instance of a “recursive”[1] calculation in GREET.
B = 92,986	WTT energy of crude in Btu consumed to recover one million Btu of crude as feedstock used in US refineries. This is a GREET calculation that includes losses and delivery to the oil refinery.
C = 76,209	WTT energy in Btu required to produce 1 million Btu of residual oil. This is calculated from the WTT analysis of residual oil and is a GREET calculation.
D = 1.0000	Loss factor[2] for Residual Oil which is a GREET default value.
E = 148,433	WTT energy required in Btu to produce one million Btu of diesel. This value is calculated from the WTT analysis of diesel from GREET.
F = 1.0002	Loss factor[2] for diesel fuel which is default GREET value.
G = 189,960	WTT energy in Btu to produce one million Btu of gasoline. This value is calculated from the WTT analysis of gasoline from GREET.
H = 1.00019	Loss factor[2]for gasoline which is default GREET value.
I = 73,741	WTT energy in Btu used to produce natural gas as stationary fuel. This is a GREET calculated value.
J = 2,173,356	Total energy required in Btu to produce one million Btu of electricity. This is derived from the electricity analysis by GREET.
K = 106,317	Total energy required in Btu to produce one million Btu of electricity feedstock. This is derived from the electricity analysis by GREET.

[1] GREET employs a recursive methodology to calculate energy consumption and emissions. To calculate WTT energy and emissions, the values being calculated are often utilized in the calculation. For example, crude oil is used as a process fuel to recover crude oil. The total crude oil recovery energy consumption includes the direct crude oil consumption AND the energy associated with crude recovery (which is the value being calculated).

[2]Loss factors for petroleum fuels include refueling spillage plus evaporative losses from vehicle fueling and fuel transfer operations.

1.2 GHG Emissions from Crude Recovery

For GHG emissions, GREET only accounts for CO_2, CH_4 and N_2O. The Global Warming Potentials (GWP) for all gases are from the IPCC guidelines and are default GREET values listed in Table 1.04. For CO and VOC, the model uses adjustment factors to calculate their CO_2 equivalents and the conversion calculations is provided as a note below.

Table 1.04 Global Warming Potentials for Gases

Species	**GWP (relative to CO_2)**
CO_2	1
CH_4	23
N_2O	296

Note: Values from mmBtu to MJ have been calculated using 1055 mmBtu = 1 MJ
GREET uses a specific methodology to account for GHG emissions related to VOCs and CO:
Carbon ratio of VOC = 0.85 which is then converted as gCO_2e/MJ = g VOC*(0.85)*(44/12) = 3.1
Carbon ratio of CO = 0.43 which is then converted as gCO_2e/MJ = g CO*(0.43)*(44/12) = 1.6

The transformation of various fuel types into energy generates emissions, specific to each type of fuel and the equipment used in the transformation. An example is natural gas being combusted to generate electricity in turbines. Table 1.05 details only CO_2 emissions for each fuel type used in crude recovery. Methane, N_2O, VOC and CO contributions to total GHG emissions are detailed later in this section. Additional details for each specific fuel type are provided in sections to follow. The table provides GHG values both in $gCO_2e/mmBtu$ and gCO_2e/MJ. As an example, the use of diesel fuel in crude recovery generates 0.87 gCO_2e/MJ.

Table 1.05 CO_2 Emissions by Fuel Type (does not include other GHGs)

Fuel Type	**$gCO_2/mmBtu$**	**gCO_2/MJ**
Crude oil	54	0.05
Residual oil	63	0.06
Diesel fuel	917	0.87
Gasoline	92	0.09
Natural Gas	2,521	2.39
Electricity	1,792	1.70
Natural Gas (flared)	975	0.92
Total	**6,416**	**6.1**

Note: 1055 mmBtu= 1MJ

Table 1.06 utilizes the energy use by fuel type from Table 1.01 and calculates GHG emissions utilizing emission factors which are provided in Table 1.07. The CO_2 emission factors represent the carbon in fuel minus carbon emissions associated with VOC and CO emissions. Thus, the emission factors are different among equipment types such as engines and turbines. The carbon in fuel factors are GREET default values, except for natural gas, which is slightly different based on the AB1007 analysis. The calculations shown reflect the estimated direct emissions of CO_2 from the different equipment types excluding the carbon in VOC and CO. Note that energy use is used from Table 1.01 of this document (as an example, the value 648 is from Table 1.01 for crude oil). Table 1.06 essentially provides details on how CO_2 emissions were calculated and provided in Table 1.05.

Table 1.06 Specific Fuel Shares Contributing to CO_2 Emissions

Fuel	**Calculations**	**CO_2 emissions (gCO_2/mmBtu)**
Crude Oil	648 *(crude oil emissions factor + total CO_2 emissions from crude recovery)/ 10^6	54
Residual Oil	648 *(Fraction of residual oil consumed in a commercial boiler*emissions factor of a commercial boiler + emissions from crude*loss factor for emissions from crude + total emissions from residual oil)/ 10^6	63
Diesel fuel	9,726*(percentage from diesel boiler*emission factor for diesel boiler + percentage from stationary diesel engine*emissions factor for diesel engine + percentage from stationary diesel turbine*emission factor of diesel turbine + emissions from crude*loss factor + total emissions from diesel)/ 10^6 (see Table 1.08A for further details)	917
Gasoline	1,297*(emissions factor of reciprocating engine + crude emissions* loss factor + emissions from conventional gasoline)/ 10^6	92
Natural Gas	40,201*(percentage of natural gas used in an engine*emissions factor for natural gas engine + percentage of natural gas used in a small industrial boiler*emissions factor for small industrial boiler + emissions from natural gas as a stationary fuel)/ 10^6 (see Table 1.08B for further details)	2,521
Electricity	12,320*(emissions from producing feedstock + emissions from consuming feedstock)/ 10^6	1,792
Natural Gas (flared)	16,800*(emissions factor for natural gas flaring)/10^6	975

Table 1.07 Values Used in Table 1.06

Fuel	Calculations
Crude Oil	crude oil emissions factor = 77,264 (gCO_2/mmBtu) which is a GREET default.
	CO_2 emissions from crude recovery = 6,416 (gCO_2/mmBtu) which is recursively calculated from Table 1.06.
Residual Oil	fraction of residual oil consumed in a commercial boiler = 1.00 which is a GREET default value.
	emissions factor of a commercial boiler = 85,049 in gCO_2/mmBtu which is a GREET calculated value.
	emissions factor from crude = 6,963 in gCO_2/mmBtu which is a GREET calculated value.
	loss factor for emissions from crude = 1.000 also a GREET default value.
	total emissions from residual oil = 5,141 a GREET calculated value.
Diesel fuel	percentage from diesel boiler = 0.25 a default value from GREET.
	emission factor for diesel boiler = 78,167 gCO_2/mmBtu, a GREET calculated value.
	percentage from stationary diesel engine = 0.5, a GREET default value.
	emissions factor for diesel engine = 77,349 gCO_2/mmBtu, a calculated value from GREET.
	percentage from stationary diesel turbine = 0.25 a default GREET value.
	emission factor of diesel turbine = 78,179 gCO_2/mmBtu, a GREET calculated value.
	emissions from crude = 6,963 gCO_2/mmBtu, calculated from GREET.
	loss factor for emissions from crude = 1.000, a default value from GREET.
	total emissions from diesel = 9,610 gCO_2/mmBtu, a GREET calculated value.
Gasoline	emissions factor of reciprocating engine = 1,297 gCO_2/mmBtu a GREET default value.
	emissions from crude = 6,963 gCO_2/mmBtu, a GREET calculated value.
	loss factor for emissions from crude = 1.000, a GREET default value.
	emissions from conventional gasoline = 13,884 gCO_2/mmBtu, GREET calculated value.
Natural Gas	percentage of natural gas used in an engine = 0.5, GREET default.
	emissions factor for natural gas engine = 56,551 gCO_2/mmBtu, a GREET calculated value
	percentage of natural gas used in a small industrial boiler = 0.5, a GREET default.
	emissions factor for small industrial boiler = 58,176 gCO_2/mmBtu, a GREET calculated value
	emissions from natural gas as a stationary fuel = 5,349 gCO_2/mmBtu, a GREET calculated value.
Electricity	emissions from producing feedstock = 7,737 gCO_2/mmBtu, a GREET calculated value from electricity pathway.
	emissions from consuming feedstock = 137,734 gCO_2/mmBtu, a GREET calculated from electricity pathway.
Natural Gas (flared)	emissions factor for natural gas flaring =58,048 gCO_2/mmBtu, a GREET default value.

Tables 1.08A and 1.08B provide additional details on emissions coming from diesel, natural gas and electricity generation. Carbon dioxide emissions from crude oil, residual oil, and gasoline combustion cannot be further broken down according to equipment type because they are used in only one equipment type: industrial boilers (crude oil and residual oil) and reciprocating engines (gasoline). The values from crude oil, residual oil, and gasoline combustion are provided by the emission factors for these fuels as detailed in Tables 1.06 and 1.07. In Tables 1.08A and 1.08B, details for CO_2 emissions are provided for diesel and natural gas used as a fuel in crude recovery operations. All values in Tables 1.08A and 1.08B are GREET default values and subsequent GREET calculated values. Note that Tables 1.08A and 1.08B detail how values reported in Table 1.06 for diesel and natural gas are calculated.

Table 1.08A CO_2 Emissions from Diesel

Equipment Type	**Equipment Shares**	**Emissions Factor**	**gCO_2/mmBtu**
Commercial Boiler	25%	78,167	190.06
Stationary Reciprocating Engine	50%	77,349	376.15
Turbine	25%	78,179	190.09
Crude Oil and Diesel Production			161.19
Total			**917**

Table 1.08B CO_2 Emissions from Natural Gas

Equipment Type	**Equipment Shares**	**Emissions Factor**	**gCO_2/mmBtu**
Stationary Reciprocating Engine	50%	56,551	1,137
Small Industrial Boiler	50%	58,176	1,169
As Stationary Fuel		5,349	215
Total			**2,521**

Tables 1.09 through 1.12 detail CO_2 emissions from electricity generation. They essentially detail how electricity values are calculated in Table 1.06. The emissions factor are GREET calculations. For electricity, it is broken down into emissions from feedstock production (recovering feedstock such as coal from mines and transporting to a facility) and feedstock consumption (actual use in a boiler). Table 1.09 details CO_2 emissions from feedstock consumption and values used here are provided in Table 1.10.

Table 1.09 Detailed CO_2 Emissions from Feedstock Consumption for Electricity

Feedstock As Fuel	**Calculation**	**gCO_2/mmBtu**
Natural Gas	1,697*(A/G) (note: this is a recursive calculation and all in this column)	941
Coal	1,697*(B/G)	383
Biomass	1,697*(C/G)	29
Nuclear	1,697*(D/G)	126
Residual Oil	1,697*(E/G)	1
Other Sources*	1,697*(F/G)	217
Total		**1,697**

*Other sources include hydro, wind, geothermal etc.

Table 1.10 Energy Breakdown from Electricity (Feedstock Consumption) as Used in Table 1.11

Fuel	Conv. Efficiency	Generation Mix	Relationship of Conversion Efficiency and Energy Use	Energy Use (Btu/mmBtu)	Factor	Description
Residual Oil	34.8%	0.05%	$(10^6/0.348)*(1/1-0.081)*0.0005$	1,563	E	Energy used as residual oil (Btu/mmBtu), a GREET calculation.
Natural Gas	38.9%	43.1%	$(10^6/0.389)*(1/1-0.081)*0.431$	1,204,871	A	Energy used as natural gas (Btu/mmBtu), a GREET calculation.
Coal	34.1%	15.4%	$(10^6/0.341)*(1/1-0.081)*0.154$	490,460	B	Energy used as coal (Btu/mmBtu), a GREET calculation.
Biomass	32.1%	1.1%	$(10^6/0.321)*(1/1-0.081)*0.011$	37,288	C	Energy used as biomass (Btu/mmBtu), a GREET calculation.
Nuclear	100%	14.8%	$(10^6/1.00)*(1/1-0.081)*0.148$	161,262	D	Energy used as nuclear (Btu/mmBtu), a GREET calculation.
Other	100%	25.5%	$(10^6/1.00)*(1/1-0.081)*0.255$	277,911	F	Energy used as other sources (Btu/mmBtu), a GREET calculation.
Total energy used to produce electricity (Btu/mmBtu), GREET calculation				**2,173,356**	**G**	

“Other” is a combination of hydro, wind, geothermal, etc.

Table 1.11 provides information on CO_2 emissions from feedstock production related to electricity. The values used to perform the calculations in Table 1.11 are provided in Table 1.12. All values are GREET calculations. The values in Tables 1.09 and 1.11 provide the total for electricity which adds to 1697 + 95 = 1792 gCO_2/mmBtu, shown for electricity in Table 1.06.

Table 1.11 Detailed CO_2 Emissions from Feedstock Production

Feedstock	**Calculation**	**gCO_2/mmBtu**
Natural Gas	$95*(A*B/C)/10^6$	80
Coal	$95*(D*E/C)/10^6$	7
Biomass	95*((F*G)/H*I)/C	1
Nuclear	95*(J*K/(L*1000*3412))/C	7
Residual Oil	$95*M*(N*O +P/C)/10^6$	0
Total		**95**

Table 1.12 Values Used in Table 1.11 Calculations

Variable	**Value**	**Description**	**Reference**
A	1,204,871	Energy used as natural gas (Btu/mmBtu)	GREET calculation
B	73,741	Energy used as natural gas for electricity generation (Btu/mmBtu)	GREET calculation
C	106,137	Total energy used to produce feedstocks (Btu/mmBtu)	GREET calculation
D	490,460	Energy used as coal (Btu/mmBtu)	GREET calculation
E	16,930	Energy used as coal gas for electricity generation (Btu/mmBtu)	GREET calculation
F	37,288	Energy used as biomass (Btu/mmBtu) GREET default	GREET default
G	548,999	Sum of energy used from fertilizers, pesticides, farming, and transportation for producing biomass (Btu/dry ton)	GREET default
H	16,811,000	Low heating value of farmed trees (Btu/ton)	GREET default
I	100 %	Shares of woody biomass	GREET default
J	161,262	Energy used as nuclear fuel (Btu/mmBtu)	GREET calculation
K	1,099,450	Energy used as nuclear fuel for electricity generation (Btu/mmBtu)	GREET calculation
L	6.926	Conversion factor for nuclear power plants	GREET default
M	1,563	Energy use from residual oil as a stationary source (Btu/mmBtu)	GREET calculation
N	92,986	Energy used from crude oil (Btu/mmBtu)	GREET calculation
O	1.0	Loss factor for residual oil	GREET default
P	76,209	Energy used as residual oil for electricity generation (Btu/mmBtu)	GREET calculation

Table 1.13 provides details on CH_4, N_2O, VOC and CO emissions generated during the combustion of the different fuels listed in these tables. These values are calculated from default GREET values for sources that are used in crude recovery.

Table 1.13 CH_4, N_2O, VOC and CO Emissions from Crude Recovery

	CH_4 Emissions	**N_2O Emissions**	**VOC Emissions**	**CO Emissions**
Fuel Type	(gCH_4/mmBtu)	(gN_2O/mmBtu)	(gVOC/mmBtu)	(gCO/mmBtu)
Crude oil	0.012	0.00	0.0003	0.034
Residual oil	0.063	0.00	0.0006	0.032
Diesel fuel	1.00	0.02	0.513	2.174
Gasoline	0.30	0.00	2.322	17.141
Natural gas	13.0	0.04	1.139	7.946
Electricity	2.90	0.03	0.186	1.194
Natural gas (flared)	0.80	0.02	0.042	0.436
Total (without non-combustion)	18.075	0.107	4.214	28.829
Non-combustion	2.255	0.00	0.702 (bulk terminal)	0.000
Total	**20.33**	**0.107**	**4.916**	**28.83**

Table 1.14 summarizes the total GHG emissions for crude recovery. The total is calculated as gCO_2e where non-CO_2 GHG gasses have been converted to CO_2 equivalents using their GWP detailed earlier. It also shows how GREET accounts for CO and VOC emissions in its calculation of pathway GHG emissions.

Table 1.14 Total GHG Emissions from Crude Recovery

	(g/mmBtu)	**Formula**	**gCO_2e/mmBtu**	**gCO_2e/MJ**
CO_2	6,416	6416*1	6,416	6.08
CH_4	20.33	20.33*23	467.60	0.44
N_2O	0.107	0.107*296	31.672	0.03
CO	28.829	28.829*0.43*(44/12)	45.303	0.04
VOC	4.916	4.916*0.85*(44/12)	15.324	0.01
Total GHG emissions			**6,976**	**6.60**

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SECTION 2. CRUDE TRANSPORT

2.1 Energy Use for Crude Transport

Crude transportation energy use is based on the weighted mix for crude recovery (average CA crude) and the corresponding transport mode. The transport distances have been calculated to be 266 miles via pipeline and 3,550 miles via oil tanker. These values were utilized by TIAX in their AB 1007 work completed in 2007. Details of how the transport miles were calculated are provided in Table 2.01.

Table 2.01 Crude Oil Transport Details from AB 1007 Work

				Crude Pipeline		Crude Shipping	
Crude Supply (2005)	Annual Consumption		Mix	Destination	Distance	Destination	Distance
Alaska	140	million barrels	21%	Valdez	800	SF	1,700
Domestic	260	million barrels	38%	Refineries	50	--	0
Foreign	280	million barrels	41%	Ras Tanura	200	Long Beach	7,778
Annual Total	680	million barrels			266		3,553

The average pipeline and ocean tanker distances were calculated using the weighted consumption data in Table 2.01 and shown below:

- Pipeline Transport: 266 = (800*21%)+(50*38%)+(200*41%)
- Ocean Tanker Transport: 3,553 = (1700*21%)+(0*38%)+(7778*41%)

The two modes of transport are utilized to transport crude to California refineries. Details of how energy use is calculated for both types of modes of transport are detailed in Table 2.02 below with values used in the calculation provided in Table 2.03. Both modes utilize common factors such as lower heating values (LHV) and density of crude, and transport mode specific factors such as energy consumed per mile of transport to calculate energy use for specific distances transported.

Table 2.02 Details of Energy Consumed for Crude Transport

	Detailed Calculations	**Btu/mmBtu**
Feed Loss	$(1.000062-1)*10^6$	62
Ocean Tanker	(Density of crude/LHV of crude)*(Energy consumed)*(miles traveled)*(1/454)*(1/2000)*(1+0.169)*10^6	5,845
Pipeline	(Density of crude/LHV of crude)*(Energy consumed)*(miles traveled)*(1/454)*(1/2000)*(2.279)*10^6	4,169
Total		**10,076**

Table 2.03 Values for Equations Used in Table 2.02

Description	**Value**	**Source**
Loss Factor in Crude T&D	1.000062	GREET Calculation
Miles traveled by Ocean Tanker (miles)	3,550	AB 1007 value
Pipeline transport (miles)	266	AB 1007 value
Density of crude (grams/gallon)	3,205	GREET default
Lower heating value (LHV) of crude (Btu/gallon)	129,670	GREET default
Energy consumed by Ocean Tanker (Btu/ton-mile)	51	GREET calculation based on tanker size
Energy consumed by Pipeline (Btu/ton-mile)	253	GREET default
Conversion from pound to grams	1/454	
Conversion from ton to pounds	1/2000	
WTT Energy Factor for Residual Oil	0.169	GREET calculation
WTT Energy Factor for Electricity including electricity	2.279	GREET calculation

2.2 GHG Emissions from Crude Transportation

Table 2.04 details CO_2 emissions related to crude transport and distribution. The ocean tanker miles used in calculations is 3,550 and for pipeline it is 266 as detailed in the energy calculations section of Crude transport and distribution (section 2.1). Table 2.05 provides values for various terms used in Table 2.04.

Table 2.04 Crude Transport CO_2 Emissions

Mode	**Formula**	**gCO_2/mmBtu**	**gCO_2/MJ**
Ocean Tanker	(Density of crude/LHV of crude)*(miles traveled) *(1/454)*(1/2000)*((Energy intensity on trip from origin to destination*(emission factor for bunker fuel + emission factor for residual oil)) + (Energy intensity on return trip*(emission factor for bunker fuel + emission factor for residual oil))	483	0.46
Pipeline	(Density of crude/LHV of crude)*(Energy intensity of pipeline)*(miles traveled)*(1/454)*(1/2000)*(emission factor for electricity)	266	0.25
Total		**749**	**0.71**

Table 2.05 Values of Properties Used in Table 2.04

Parameters	**Values**	**Sources**
Miles traveled by Ocean Tanker (miles)	3,550	AB 1007 value
Pipeline transport (miles)	266	AB 1007 value
Density of crude (grams/gallon)	3,205	GREET default
Lower heating value (LHV) of crude (Btu/gallon)	129,670	GREET default
Energy intensity of Ocean Tanker on trip to destination (Btu/ton-mile)	27	GREET default
Energy intensity of Ocean Tanker on return trip (Btu/ton-mile)	24	GREET default
Energy intensity of Pipeline (Btu/ton-mile)	253	GREET default
Conversion from mmBtu to MJ	1/1055	
Emission factor for Bunker Fuel (Carbon in fuel)	84,515	GREET default
WTT Emission factor for Residual Oil	12,097	GREET default
Emission factor for Electricity	145,220	GREET default

Table 2.06 details CH_4 emissions for crude transport and distribution utilizing ocean tanker and pipeline transport modes. The emissions are GREET defaults. VOC and

N_2O emissions are small for this group and not detailed but included in the total GHG emissions calculations for this part and shown in Table 2.07.

Table 2.06 Crude Transport CH_4 Emissions

	gCH_4/mmBtu
Ocean Tanker	
Residual oil, combustion	0.503
Pipeline	
Electricity	0.426
Non-combustion	69.54*
Total	**70.47**

*This is the amount of CH_4 in associated gases and is a GREET default.

Table 2.07 Total GHG Emissions from Crude Transport and Distribution

GHG	**g/mmBtu**	**Formula to convert to CO_2e**	**gCO_2e/mmBtu**	**gCO_2e/MJ**
CO_2	749	749*1	749	0.71
CH_4	70.47	70.47*23	1,620	1.53
N_2O	0.015	0.015*296	4.44	0.00
CO	1.302	1.302*0.43*(44/12)	2.05	0.00
VOC	0.483	0.483*0.85*(44/12)	1.51	0.00
Total GHG emissions			**2,377**	**2.24**

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SECTION 3. CRUDE REFINING

3.1 Energy Use for Crude Refining

Wang et al.[3] analyzed refining efficiency on a process allocation basis and based on this analysis, calculated energy efficiency for the various streams probable from a crude refining facility. The refinery efficiency is based on a model refinery result combined with EIA data for petroleum production. The 86.7% refinery efficiency value used here is based on the AB1007 report prepared by the Energy Commission. The refinery efficiency takes into account additional energy required for sulfur removal. Based on their analysis, ULSD was calculated to have a refining efficiency of 86.7% which has been used in calculations here, both for energy and GHG emissions. This value is used to calculate the energy inputs necessary for ULSD as detailed below in Table 3.01.

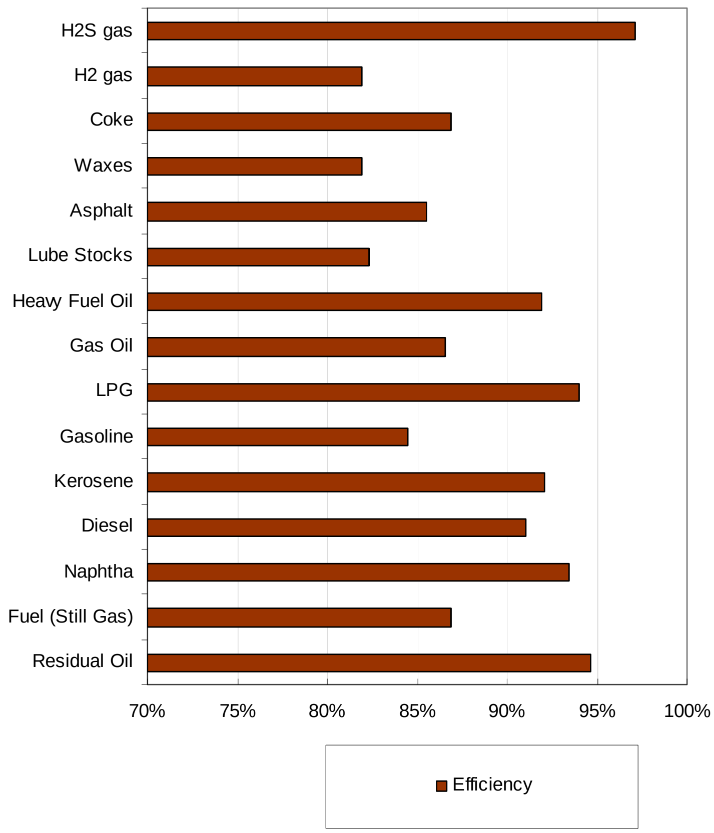


Figure 3. Efficiency of Various Fuel Products

[3] Refinery Energy Efficiency Allocation Analysis based on: Wang, M., et al. (2004) Allocation of Energy Use in Petroleum Refineries to Petroleum Products Implications for Life-Cycle Energy Use and Emission Inventory of Petroleum Transportation Fuels. LCA Case Studies.

Table 3.01 Energy Use for Crude Refining

Fuel Type	Fuel Shares	Relationship of Refinery Efficiency (0.867) and Fuel Shares	Btu/mmBtu
Residual Oil	6%	$(10^6)(1/0.867 - 1)(6\%)$	9,241
Natural Gas	40%	$(10^6)(1/0.867 - 1)(40\%)$	61,609
Electricity	4%	$(10^6)(1/0.867 - 1)(4\%)$	6,161
Refinery Still Gas	50%	$(10^6)(1/0.867 - 1)(50\%)$	77,011

The values in Table 3.01 are adjusted to account for upstream losses in the WTT energy use. Table 3.02 depicts the adjustments to the values from the table above for each fuel type accounting for loss factors associated with the WTT energy for each fuel used during crude refining operations. Table 3.03 details the values and descriptions for the formulas presented in Table 3.02.

Table 3.02 Adjustment to Crude Recovery

Fuel Type	Formula	Btu/mmBtu
Residual Oil	$11{,}006*(1 + (A*B+C/10^6))$	10,805
Natural Gas	$73{,}373*(1 + D/ 10^6)$	66,152
Electricity	$7{,}337*((E+F)/ 10^6)$	14,044
Refinery still gas	$91{,}716*(1 + (A/ 10^6))$	84,172
Total energy for refining		**175,173**

Table 3.03 Details for Entries in Table 3.02

Quantity	Description
A = 92,986	Energy required to produce crude as feedstock for use in US refineries, a GREET calculated value.
B = 1.000	Loss factor, a GREET default.
C = 76,209	Energy in Btu required to produce 1 million Btu of residual oil, a GREET calculated value.
D = 73,741	Energy required to produce natural gas as a stationary fuel, a GREET calculated value.
E = 106,137	Total energy required to produce feedstock for power generation, calculated in GREET electricity analysis.
F = 2,173,356	Energy required in Btu to produce one million Btu of electricity which is calculated in GREET electricity analysis.

3.2 GHG Emissions from Crude Refining

The transformation of energy from the various fuels above to useful energy required in the processing of crude to ULSD generates equipment specific GHG emissions. GHG emissions include CO_2 as well as non-CO_2 GHG gasses. This section first presents the CO_2 emissions followed by non-CO_2 emissions which are then converted to CO_2 equivalents and then summarized at the end of this section (3.2).

Table 3.04 lists CO_2 emissions by fuel type generated during the refining of crude to ULSD. Detailed emissions for each fuel type are provided in Tables 3.05 and 3.06.

Table 3.04 CO_2 Emissions by Fuel Type

Fuel Type	gCO_2/mmBtu	gCO_2e/MJ
Residual oil	898	0.85
Natural gas	3,915	3.71
Electricity	896	0.85
Refinery Still Gas	4,481	4.25
Total	**10,190**	**9.66**

Tables 3.05 and 3.06 provide details of CO_2 emissions related to use of residual oil in refineries for processing crude to ULSD.

Table 3.05 CO_2 Emissions from Residual Oil Use in Refineries from Table 3.04

Calculation Details	gCO_2/mmBtu	Reference
9241*(emissions factor for an industrial residual oil boiler*Percentage of residual oil used in industrial residual oil boiler + emissions from residual oil + emissions from crude oil)/10^6	898	GREET calculation

Note: the value of 9,241 is from Table 3.01

Table 3.06 Values for Use in Table 3.05

Factor	Value	Reference
emissions factor for an industrial residual oil boiler	85,045 gCO_2/mmBtu	GREET default
Percentage of residual oil used in industrial residual oil boiler	100%	GREET default
emissions from residual oil	5,137 gCO_2/mmBtu	GREET default
emissions from crude oil	6,960 gCO_2/mmBtu	GREET default

Tables 3.07 and 3.08 provide details on CO_2 emissions from natural gas use in crude refining to ULSD.

Table 3.07 CO_2 Emissions from Natural Gas from Table 3.04

Calculation details	gCO_2/mmBtu	Reference
66152*(share from NG engine*emission factor for NG engine)+(share from large turbine*emission factor for large turbine +(share from large industrial boiler*emission factor for large industrial boiler) + (share from small industrial boiler *emission factor for small industrial boiler) + Emissions from natural gas as a stationary fuel/106	3,915	GREET calculation

Table 3.08 Details of Values Used in Table 3.07

Description	Shares	Emissions factor (gCO_2/mmBtu)	Reference
Share from natural gas engine	0%	56,551	GREET default
Share from large turbine	25%	58,179	GREET default
Share from large industrial boiler	60%	58,198	GREET default
Share from small industrial boiler	15%	58,176	GREET default
Emissions from natural gas as a stationary fuel		5,349	GREET calculation

Electricity contributions to GHG emissions are provided in Tables 3.09 to 3.15, both for feedstock production and feedstock consumption.

Table 3.09 CO_2 Emissions from Electricity from Table 3.04

	Calculation details	gCO_2/mmBtu
Electricity as feedstock	$6161*7737/10^6$	48
Electricity as fuels	Contribution from Residual Oil= 2 gCO_2/mmBtu Contribution from Natural Gas = 433 gCO_2/mmBtu Contribution from Coal = 416 gCO_2/mmBtu	849
Total		**896**

Note: 6,161 Btu/mmBtu is energy of electricity used in ULSD refining (see table 3.01)

To calculate CO_2 emissions above:

- CO_2 emission from power plant + VOC and CO emissions conversion from power plant, where:

CO_2 from power plant: 6161*(Specific Power Plant Emission Factor)* % of generation mix/(1- % assumed loss in transmission)/10^6, then convert from g/kWh to gCO_2e/mmBtu by multiplying g/kWhr by (10^6/3412).

- VOC and CO conversion are from GREET defaults.

Table 3.10 Type of Power Generation Plant and Associated Emission Factors Used in Table 3.09

Power Plant Type	**Generation Mix**	**CO_2 Emission Factor (g/kWhr)**	**Loss in transmission**	**Convert to CO_2e (g/mmBtu)**
Oil-fired	0.05%	834	8.1%	2
Natural Gas-fired	43.1%	510	8.1%	433
Coal-fired	15.4%	1,374	8.1%	416

Table 3.11 provides a breakdown of CO_2 emissions from electricity generation into feedstock production and feedstock consumption (as fuels). Production refers to mining or other methods to actually procure the feedstock necessary for use in electricity generation. Feedstock production accounts for about 5.3% of the total emissions and feedstock consumption to generate electricity accounts for the balance of 94.7%.

Table 3.11 CO_2 Emissions from Electricity

	gCO_2/mmBtu	**% share**
Feedstock Production	7,737	5.3%
Feedstock Consumption	137,734	94.7%
Total	**145,471**	

Feedstock Production 7,337 g CO_2/mmBtu is calculated as shown in table 3.13
Feedstock Consumption 137,734 g CO_2/mmBtu is calculated as shown in table 1.06

CO_2 emission of ULSD refining is also from vented sources (non-combustion) as shown in table 3.12

Table 3.12 CO_2 Emissions from Non-Combustion Sources

	gCO_2/mmBtu	**gCO_2e/MJ**
Non-combustion	1,117	1.06

This is calculated from assumed CO_2 vented from bulk terminals (1,172 g/mmBtu) and ratio efficiencies of conventional gasoline refining (86%) on ULSD refining (86.7%): 1172*(1-86%)/(1-86.7%). Table 3.13 and 3.14 provide details of CO_2 emissions related to feedstock production.

Table 3.13 CO_2 Emissions from Electricity (feedstock production) as Shown in Table 3.12

	Relationship of Energy Use and CO_2 Emissions	**Energy Use Emissions gCO_2/mmBtu**
Residual oil	1,563*(crude emission factor*crude loss factor + residual oil emission factor)/10^6	19
Natural gas	1,204,871*(natural gas emission factor)/ 10^6	6,445
Coal	490,460*(coal emission factor)/ 10^6	635
Biomass	37,288*(biomass emission factor)/emissions of farmed trees)	90
Nuclear	161,262*(uranium emission factor)/(conversion factor for nuclear power plants*1000*3412)	482
Other	VOC emissions*Carbon ration of VOC/Carbon ratio of CO_2 + CO emissions*Carbon ration of CO/Carbon ratio of CO_2	67
Total		**7,737**

The numerical values (1,563; 1,204,871; 490,460; 37,288; and 161,262) used in the table above are the energies from those feedstocks used at power plants to generate one mmBtu of electricity at the use site (see detailed calculations in table 3.15)

Table 3.14 Factors and Values for Use in Table 3.13

Description	**GREET default value**
Crude emission factor	6,963 gCO_2/mmBtu
Crude loss factor	1.000
Residual oil emission factor	5,141 gCO_2/mmBtu
Natural gas emission factor	5,349 gCO_2/mmBtu
Coal emission factor	1,295 gCO_2/mmBtu
Biomass emission factor (sum of factors for farmed trees, fertilizer and pesticides)	40,367 gCO_2/mmBtu
Emission of farmed trees	16,811,000 gCO_2/mmBtu
Uranium emission factor	70,591 gCO_2/mmBtu
Conversion factor for uranium plants	6.926 gCO_2/mmBtu
Carbon Ratio of VOC	0.85
Carbon Ratio of CO	0.43
Carbon Ratio of CO_2 (12/44)	0.27

Table 3.15 shows the relationship between the energies used from feedstocks at a power plant (to produce one mmBtu of electricity to the use site) and the conversion efficiencies of electrical generation for each feedstock used, after taking into account the loss (8.1%) from the transmission of electricity.

Table 3.15 Energy Breakdown from Electricity (Feedstock Consumption) as used in Table 3.13

	Conversion Efficiency (from AB 1007)	**Generation Mix**	**Relationship of Conversion Efficiency and Energy Use**	**Energy Use (Btu/mmBtu)**
Residual oil	34.8%	0.05%	$(10^6/0.348)*(1/1-0.081)*0.0005$	1,563
Natural gas	38.9%	43.1%	$(10^6/0.389)*(1/1-0.081)*0.431$	1,204,871
Coal	34.1%	15.4%	$(10^6/0.341)*(1/1-0.081)*0.154$	490,460
Biomass	32.1%	1.1%	$(10^6/0.321)*(1/1-0.081)*0.011$	37,288
Nuclear	100%	14.8%	$(10^6/1.00)*(1/1-0.081)*0.148$	161,262
Other	100%	25.5%	$(10^6/1.00)*(1/1-0.081)*0.255$	277,911
Total				**2,173,355**

Note: "Other" is a combination of hydro, wind, geothermal, etc. 0.081 is the loss in electricity transmission by GREET default

Tables 3.16 and 3.17 detail CO_2 emissions from use of refinery still gas in crude refining operations.

Table 3.16 CO_2 Emissions from Use of Refinery Still Gas

Calculation	Value (gCO_2/mmBtu)	Reference
Emissions from refinery still gas as a stationary fuel* (share from engine*natural gas engine emission factor) + (share from large turbine*emission factor for large natural gas turbine) + (share from large industrial boiler*emission factor for large industrial boiler) + (share from small industrial boiler *emission factor for small industrial boiler) + (Emissions from natural gas as a stationary fuel)/106	4481	GREET calculation

Table 3.17 Values Used in Table 3.16

Description	Shares	Emission Factor (gCO_2/mmBtu)	Reference
Natural Gas, engine	0	56,551	GREET default
Natural Gas, large turbine	25%	58,179	GREET default
Natural Gas, large Industrial boiler	60%	58,198	GREET default
Natural Gas, small Industrial boiler	15%	58,176	GREET default
Emissions from natural gas as a stationary fuel		5,349	GREET default
Emissions from refinery still gas as a stationary fuel		91,716	GREET default

CH_4 emissions and N_2O emissions from crude refining are shown in Tables 3.18 and 3.19. VOC and CO contributions are small and are not further detailed here. They are however included for presentation in Table 3.20.

Table 3.18 CH_4 Emissions Converted to CO_2 Equivalent

Fuel	gCH_4/mmBtu	gCO_2e/MJ
Residual oil	0.92	0.02
Natural gas	8.69	0.19
Electricity	1.43	0.03
Refinery Still Gas	0	0
Total	**11.04**	**0.24**

Table 3.19 N_2O Emissions

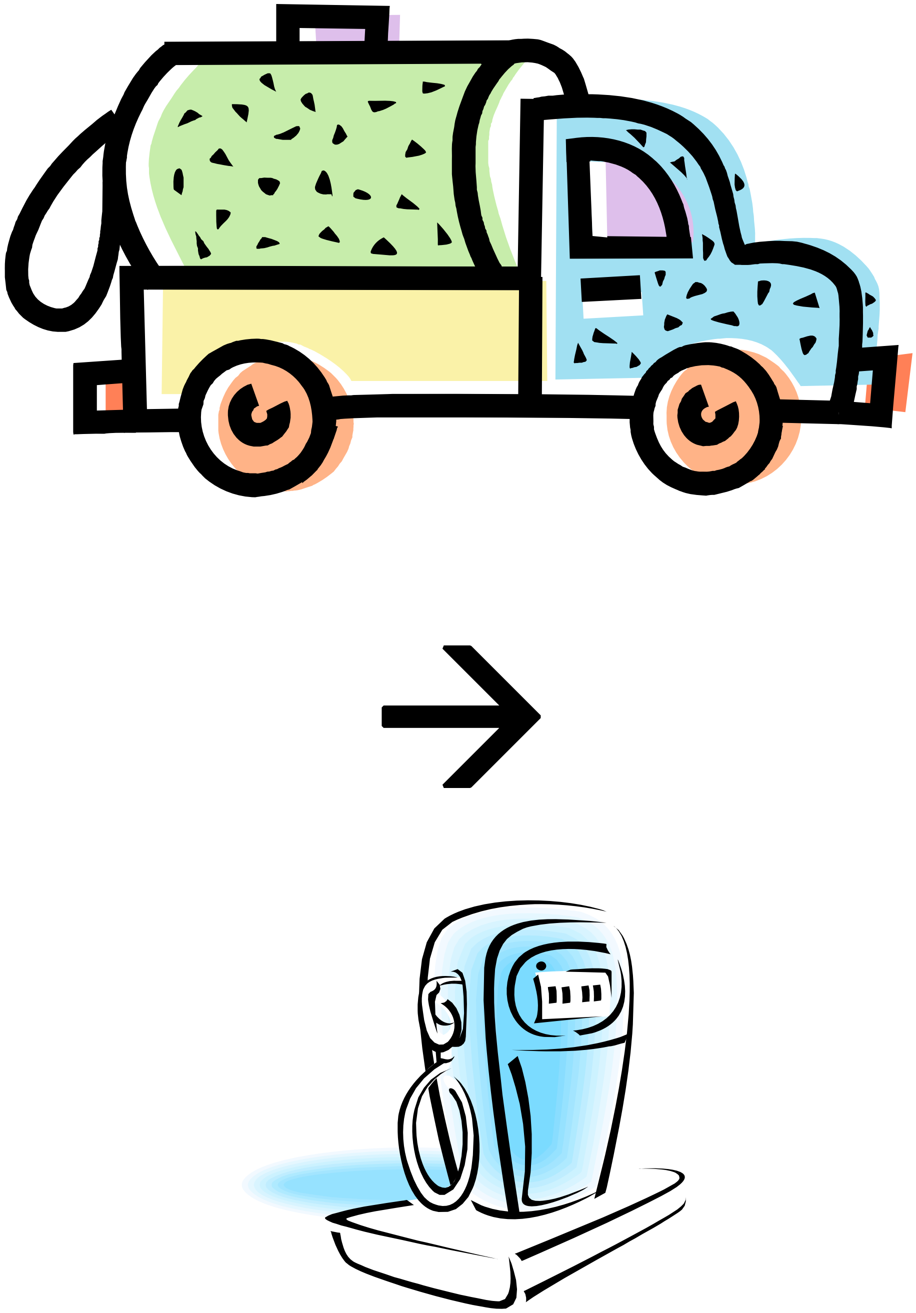
Fuel	**gN_2O/mmBtu**
Residual oil	0.01
Natural gas	0.04
Electricity	0.01
Refinery Still Gas	0.05
Total	**0.11**

Table 3.20 summarizes the total GHG emissions from crude refining. Note that non-CO_2 gasses have been converted to CO_2 equivalents using conversion factors detailed earlier in this document.

Table 3.20 Emissions from Crude Refining

	(g/mmBtu)	**Conversion to CO_2e**	**gCO_2e/mmBtu**	**gCO_2e/MJ**
CO_2	10,190	10,190 *1	10190	9.66
CH_4 (combustion)	11.04	11.04*23	253.9	0.24
CH_4 (non-combustion)	--	1,117	1,117	1.06
N_2O	0.11	0.11*296	32.6	0.03
CO	4.599	4.599*0.43 *(44/12)	7.3	0.01
VOC	0.809	0.809*0.85*(44/12)	2.5	0.002
Total GHG Emissions			**11,603**	**11.0**

SECTION 4. ULSD TRANSPORTATION AND DISTRIBUTION



4.1 Energy Use for Transport and Distribution of ULSD

Table 4.01 shows the energy inputs used in transporting ULSD to trucking terminals. The energy intensity of 253 Btu/ton-mi is a default GREET value based on a composite of natural gas compressor prime movers. The 50 mile distance is based on an average for California pipeline delivery and is documented in the AB1007 report. The fuel shares input assumption is 100% electric motors based on the AB1007 analysis of petroleum infrastructure in California. The energy intensity is multiplied by an adjustment factor for each type of pipeline motor. For this case, the electric motor adjustment factor is 100%, a GREET default value. The total energy is then calculated including the WTT energy to produce electricity.

Table 4.02 shows the energy inputs for truck transport. The calculation is based on a tanker truck capacity of 9,000 gallons (25 metric tons) and a transport distance of 50 miles. The 50 mile distance is based on a survey of California fuel delivery trucks and is documented in the AB1007 report. GREET calculates the diesel energy per ton mile based on cargo capacity of the truck and its fuel economy.

Table 4.03 shows the total energy calculations used in GREET. Here the pipeline and truck is weighted by the fraction of fuel delivered by each mode. 80% of the gasoline is assumed to be piped to a blending terminal because some refineries fill trucks at the loading rack adjacent to the refinery. 99.4% of the gasoline is assumed to be transported to fueling stations by delivery trucks. The remaining 0.6% corresponds to the few fueling stations where gasoline is provided directly by pipeline. Table 4.04 details the values used in the formulas presented in Table 4.03. The total transport energy for ULSD shown in Table 4.02 includes energy associated with feed loss, which is calculated based on the VOC emissions (g/mmBtu) from the bulk terminal and refinery stations (see note below Table 4.03).

Table 4.01 Energy Use for Transport and Distribution via Pipeline

	Energy Intensity (Btu/ton-mile)	**Distance from Origin to Destination (miles)**	**Type of Power Generation**	**Shares of the type of turbine used**	**Distributed by pipeline**
Pipeline	253	50	Electric Motor	100 %	80%*

* Assumed 20% transported directly from refinery terminal rack

Table 4.02 Energy Use for Transportation and Distribution ULSD via HDD Truck

	Energy Intensity (Btu/ton-mile)	**Distance from Origin to Destination (miles)**	**Capacity (tons)**	**Fuel Consumption (miles/gal)**	**Energy Consumed of HHD truck (Btu/ mile)**	**Shares of Diesel used**	**Distributed by truck**
HDD Truck	1,028	50	25	5	25,690	100%	99.4%

* Assumed 0.6% ULSD is transported directly by pipeline to about 50 stations

Table 4.03 Details of Transportation and Distribution for ULSD

Transport mode	**Details Calculations**	**Btu/mmBtu**
Feed Loss	$(1.000145 – 1)*10^6$	145
ULSD transported by pipeline	(Density of ULSD/LHV of ULSD)*(1/454)*(1/2000)*(energy consumed by pipeline)*(miles transported one-way)*100%*100%*(2.279)*80%*10^6	625
ULSD Distribution by HHD Truck	(Density of ULSD/LHV of ULSD)*(1/454)*(1/2000)*(energy consumed by HHD truck)*(miles transported one-way+ miles transported one-way backhaul)*100%*(1+0.241)*99.4%*10^6	3,444
Total		**4,214**

Note: Loss factor = [(VOC from bulk terminal + VOC from refinery stations)/ULSD Density)*(ULSD LHV/106)] + 1

Table 4.04 describes the values used in the formulas presented in Tale 4.03.

Table 4.04 Values of Properties Use in Table 4.03

Description	**Value**	**Source**
Loss Factor in ULSD T&D	1.000145	GREET default
Lower heating value of ULSD (Btu/gallon)	127,464	AB 1007 value
Density of ULSD (grams/gallon)	3,142	GREET default
Energy consumed by Pipeline (Btu/ton-mile)	253	GREET default
Conversion from pound to grams	1/454	
Conversion from ton to pounds	½,000	
Energy intensity of ULSD transported by HHD truck (Btu/ton-mile)	1,028	AB 1007 value
ULSD transport one-way (mile)	50	AB 1007 value
Energy consumed in electricity used as transportation fuel in ULSD Production	2.279	GREET calculation
Energy consumed in diesel used as transportation fuel in ULSD Production	0.241	GREET calculation
VOC from bulk terminal	1.5	GREET Default
VOC from refinery stations	3.42	GREET Default

Note:
2.279 is an electricity adjustment factor in GREET = (energy consumed to produce feedstock + Energy consumed to produce electricity)/106
0.241 is the diesel adjustment factor in GREET = (energy from crude oil for use in the US refineries * feed loss + WTT energy of conventional diesel)/106

4.2 GHG Emissions from Transportation and Distribution of ULSD

Table 4.05 details only CO_2 emissions for the transport and distribution of finished ULSD for delivery to a blending station.

Table 4.05 CO_2 Emission Calculations for ULSD Transportation and Distribution

	Miles traveled 1-way	**Energy Intensity (Btu/mile-ton)**	**Assumed % usage**	**gCO_2/mmBtu**	**gCO_2/MJ**
Transported by Pipeline	50	253	80%	40	0.04
Distributed by HHD Truck	50	1028	99.4%	262	0.25
Total				**302**	**0.29**

Note:
- For pipeline: assumed shares of power generation are divided as following: turbine 55%, current NG engine 33% and 12% future NG engine (GREET defaults)
- For HHD Truck: assumed energy consumption at 25,690 Btu/mile, speed average 5mph, and 25 tons capacity load of ULSD.

Table 4.06 provides details for all GHG emissions for ULSD transport and distribution. This includes CH_4, N_2O, VOC and CO combined with CO_2.

Table 4.06 Details of GHG Calculations from ULSD Transport and Distribution

	g/mmBtu		**g/MJ**		**Total (gCO_2e/MJ)**
	Transportation	Distribution	Transportation	Distribution	
CO_2	40	262	0.038	0.25	0.288
CH_4 (converted to CO_2)	1.48	6.55	<0.01	<0.01	<0.01
N_2O (converted to CO_2)	0.176	1.84	<0.01	<0.01	<0.01
CO (converted to CO_2)	0.042	0.88	<0.01	<0.01	<0.01
VOC (converted to CO_2)	0.013	0.495	<0.01	<0.01	<0.01
Total GHG Emissions	**41.7**	**273.8**	**0.04**	**0.26**	**0.3**

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SECTION 5. COMBUSTION EMISSIONS FROM ULSD

5.1 Energy Use for the Combustion of ULSD

GHG emissions from the fuel occur during vehicle operation. The engine burns fuel which primarily forms CO_2. A small fraction of the fuel is emitted as CO, hydrocarbons, methane, or particulate matter. GREET assumes that CO and VOCs are converted to CO_2 in the atmosphere within a few days and this approach is followed in the CA-modified GREET. Details are provided in an earlier section. GREET uses the carbon content in the fuel to calculate GHG emissions. The calculations below show the CO_2 emissions per mmBtu and MJ of fuel. The carbon in fuel is calculated from the carbon content in the fuel and fuel density. Table 5.01 provides input values and sources of these values used in calculating carbon emissions from fuel. The average carbon ratio in ULSD is 86.5% (by weight) which translates to about 78,176 grams of CO_2 per mmBtu of fuel (74.1 gCO_2/MJ). For CH_4 and N_2O, EMFAC values are used to calculate these emissions.

Table 5.01 Inputs and Assumptions Used in GREET

Description	Value	Reference
Lower Heating Value of ULSD	127,464 Btu/gal	AB 1007 used value
Density of ULSD	3142 g/gal	AB1007 used value
Molecular weight of CO_2	44 g/mole	
Atomic weight of C	12 g/mole	
C factor	12/44 = 0.27	
Carbon ratio in ULSD	86.5 % (by weight)	GREET default
BTU to MJ conversion	1,055	Conversion from BTU to MJ
CO_2 from fuel = Density * carbon ratio in diesel/(C factor * LHV) = 78176 g CO_2/mmBtu = 74.1 g CO_2/MJ		

5.2 Vehicle CH_4 and N_2O Emissions

The California Climate Action Registry (CCAR) estimates g/mile values for CH_4 and N_2O for gasoline and diesel vehicles. To convert to g/MJ, the emissions per mile are divided by the vehicle energy consumption in MJ/mi. The AB1007 analysis summarizes both the CCAR emission factors and estimates vehicle energy consumption. The calculations are shown in Table 5.02 for passenger cars. Note that 3.7 MJ/mi is the energy consumption per mile using ULSD in a passenger vehicle. This value is calculated from a value of 4.6 for CaRFG used in AB 1007 study and adjusting for greater efficiency of diesel (dividing by 1.25 which is an assumption) which provides a value of 3.7 MJ/mile for a diesel passenger vehicle. Details of the energy consumption is detailed in the AB 1007 document.

Table 5.02 Vehicle CH_4 and N_2O Emissions

Parameter	**Emissions factor (g/mi) (assumed)**	**GWP**	**Calculation**	**GHG (gCO_2e/MJ)**
N_2O	0.06	296	0.06 * 296/3.7	4.8
CH_4	0.06	23	0.06 * 296/3.7	0.37
Vehicle Energy Consumption	3.7 MJ/mi (assumed)			--

GHG emissions from Tables 5.01 and 5.02 are combined to provide a total TTW GHG emissions of 79.27 gCO_2e for ULSD and is provided in Table 5.03

Table 5.03 Total TTW GHG Emissions for ULSD

Parameter	**GHG (gCO_2e/MJ)**
CO_2 from fuel	74.10
N_2O	4.80
CH_4	0.37
Total GHG Emissions	**79.27**

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APPENDIX B

ULTRA LOW SULFUR DIESEL PATHWAY INPUT VALUES

Average Crude Oil to CA Refineries to Make ULSD

Parameters	Units	Values	Note
GHG Equivalent			
CO_2		1	
CH_4		23	
N_2O		296	
VOC		3.1	
CO		1.6	
Crude Recovery			
Efficiency		93.9%	Crude Recovery for 2010 - user input
Fuel Shares			
Crude		1%	
Residual Oil		1%	
Conventional Diesel		15%	
Conventional Gasoline		2%	
Natural Gas		61.9%	
Electricity		19%	
Feed Loss crude recovery		0.04%	
Equipment Shares			
Commercial Boiler - Diesel		25%	
CO_2 Emission Factor	gCO_2/mmBtu	78,167	
Stationary Reciprocating Eng. - Diesel		50%	
CO_2 Emission Factor	gCO_2/mmBtu	77,349	
Turbine - Diesel		25%	
CO_2 Emission Factor	gCO_2/mmBtu	78,179	
Stationary Reciprocating Eng. - NG		50%	
CO_2 Emission Factor	gCO_2/mmBtu	56,551	
Small Industrial Boiler - NG		50%	
CO_2 Emission Factor	gCO_2/mmBtu	58,176	
Crude T&D to CA refineries			
Pipeline shares		42%	from 48 states, import
Pipeline distance	miles	150	One way
Pipeline Energy Intensity	Btu/mile-ton	253	
Ocean tanker shares		58%	from Alaska
Average distances traveled	miles	3,300	Energy Intensity 27 Btu/mile-ton, 24 for return
Crude T&D to US refineries			
Pipeline distance	miles	266	One way from 48 states, import
Pipeline Energy Intensity	Btu/mile-ton	253	
Parameters	**Units**	**Values**	**Note**

Ocean Tanker distance traveled	miles	2,100	One way from Alaska
Ocean Tanker Energy Intensity	Btu/mile-ton	27	24 Btu/mile-ton for return trip
Feed Loss in Crude T&D		1.0000616	
ULSD Refining			
Efficiency		86.7%	LSD Refining for year 2010 - user input
Process Shares			
Residual Oil		6%	
Natural Gas		40%	
Electricity		4%	
Still Gas		50%	
Equipment shares			
Large Industrial Boiler - Residual Oil		100%	
CO_2 Emission Factor	gCO_2/mmBtu	85,045	
Large Turbine - Natural Gas		25%	
CO_2 Emission Factor	gCO_2/mmBtu	58,179	
Large Industrial Boiler - Natural Gas		60%	
CO_2 Emission Factor	gCO_2/mmBtu	58,198	
Small Industrial Boiler - Natural Gas		15%	
CO_2 Emission Factor	gCO_2/mmBtu	58,176	
Power Plant - Oil-fired		0.05%	
CO_2 Emission Factor	gCO_2/kWhr	834	
Power Plant - NG-fired		43.1%	
CO_2 Emission Factor	gCO_2/kWhr	510	
Power Plant - Coal-fired		15.4%	
CO_2 Emission Factor	gCO_2/kWhr	1,374	
ULSD T&D			
Transportation by pipeline		80%	20% directly from refinery terminal rack
Distance	miles	50	
Energy Intensity	Btu/ton-mile	253	
Distribution by truck		99.4%	0.6% directly supplied by pipeline
Distance	miles	50	
Energy Intensity	Btu/ton-mile	1,028	
Loss Factor of ULSD T&D		1.000145	
Fuel Properties			
	LHV (Btu/gal)	**Density (g/gal)**	
Crude	129,670	3,205	
Residual Oil	140,353	3,752	
Conventional Diesel	128,450	3,167	
Conventional Gasoline	116,090	2,819	

CaRFG	111,289	2,828	
CARBOB	113,300	2,767	
Natural Gas	83,686	2,651	as liquid
Ethanol	76,330	2,988	
Transportation Mode			
Ocean Tanker	tons	250,000	Crude Oil
	tons	150,000	Diesel
Heavy Duty Truck	tons	25	Crude Oil
	tons	25	Diesel